# ENSURING ADEQUATE CAPACITY RESERVES

## FERC-State Commissioner Discussion
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Having an adequate reserve margin – of both generation reserves and interruptible demand – has always been and remains an important piece of electric industry reliability. The methods of achieving an excess of generation over demand in a market environment, however, may change significantly. The options for achieving capacity adequacy affect electricity costs and reliability.

Electric energy must be produced as it is consumed because generally storage of electric energy is impractical. In every region, there must be sufficient installed electric generation to supply electric energy at all times as the customers consume it (or sufficient interruptible demand and load management to reduce demand to a level that the available generators can meet). In an interconnected electrical system, each customer is served by all generators on the system rather than by an individual generator. Thus, for electric supply to any particular customer to be reliable, the generation resources in the interconnected system (supplemented by load management and price-responsive demand) must be adequate for the needs of the whole system under a variety of adverse conditions. At the extreme, if energy and operating reserves are inadequate and little or no demand response exists, reliability is compromised and curtailments or black-outs may occur.

If there are inadequate operating reserves in a regional market or load pocket, the generators serving that area at peak hours can raise their prices because there is inadequate competition or demand response to limit their collection of temporary scarcity rents. It is clear from experience in gas markets, regional electric markets, and other commodity markets that when demand pushes too close to available supply, the commodity price rises. This is clear as both a long-term trend and in peak versus off-peak price differentials. In regions where there is a wide reserve margin, the excess supply disciplines supplier market power and yields lower energy prices in peak and off-peak periods.

Historically, under monopoly regulation, utilities maintained a 15 to 20 percent reserve margin. State commissions often required utilities to maintain a specified "reserve margin" as part of their obligation to serve. This solution is problematic going forward for two reasons – first, the markets and generation that serves each extend well beyond most state boundaries, and second, few load-serving entities are now self-sufficient in generation, and rely on significant purchases from other wholesale producers.

While price-responsive demand has the potential to take the place of generation adequacy planning and be the tool system operators use to continuously balance supply and demand in real time, it is not clear when sufficient price-responsive demand will be available. Because most generation, transmission and demand management techniques cannot be put in place quickly (whether due to technological, investment, or siting and political challenges), there may be a need for regulatory policies to assure adequate region-wide capacity reserves. Therefore, we explore the options for state and federal regulators to encourage new investment through wholesale market rules and programs.

**Capacity Reserves**

System operators must continuously balance generation and load in real-time while allowing for random generation outages and load variability. This requires sufficient energy and sufficient short-term "operating reserves", a class of ancillary services made up of resources available to respond in minutes or hours in the event of system contingencies. "Capacity reserves" refers to long-term adequacy of generation and demand management (demand response and demand side management (DSM)) relative to anticipated peak loads; it is commonly expressed as a reserve margin (percentage of total generating capacity over peak load minus interruptible demand).

**Capacity assurance mechanisms**

In the Midwest, significant generation investment was built in response to energy price spikes in 1997 and 1998. Without some market mechanism or regulatory requirement for excess capacity, potential generators must examine the likely returns from energy and operating reserves markets to estimate whether future prices of energy and operating reserves will cover their investment cost, running costs, and required returns on equity. Energy price caps may need to be higher to provide enough “scarcity rent” to attract and pay for needed capacity. And regulators must be willing to tolerate occasional short-term wholesale price spikes, and reduce wholesale exposure to the spot market through long-term contracting.

There are two extreme solutions for excess capacity assurance. The free market option is to set up no formal capacity assurance mechanism, but to wait for energy and capacity prices in spot and forward markets to rise high enough to justify new investments. Traditionally, regulators and elected officials have shown little willingness to bear the consequences of the high prices, price volatility and reliability challenges that can result from this option. Proposed at the other extreme is unilateral action by the state or an ISO (independent system operator) to build and operate needed reserves.

Between these two extremes, four primary options exist to encourage new capacity construction:

1) Installed Capacity (ICAP) payments – An Installed Capacity (ICAP) obligation is an obligation imposed on load-serving entities (LSEs) to acquire a specified amount of generation capacity credits. In the Northeast ISOs, LSEs typically must acquire enough ICAP credits (MW tied to a specific generation resource) to match their peak loads plus a reserve margin of 15 - 20 percent. LSEs that fail

to meet their ICAP obligations are subject to a deficiency charge (typically based on the cost of building a new peaking generator.) LSEs may acquire the credits either through ownership of generation or through purchase of the capacity credits under contract from other generation owners. Generators used for providing ICAP credits typically must be physically capable of generating energy during a specified percentage of the year. ICAP generators typically must also offer their energy for sale into the ISO's energy market, although the offer is not accepted (whether because of the need or offer price), they may then sell their energy outside the ISO's market. It is possible to distinguish between ICAP products, as for peak v. intermediate v. baseload generation, but this has not been done in the northeast.

In the tight pools of the Northeast, the traditional ICAP requirements have evolved into markets for "capacity credits." These markets facilitate efficient exchange of "capacity credits" between entities. In the PJM area, ICAP payments averaged $0/megawatt in the fall of 2000, but averaged $177/MW-day in early 2000 before FERC imposed modifications to the ICAP structure.

2) <u>Forward contracts for new capacity</u> – This options requires each LSE to hold contracts with wholesale producers for sufficient generation and/or assured demand reduction in excess of that LSE's projected demand.

3) <u>Near-term reserve margin requirements</u> – This requires each LSE to secure control over sufficient generation and/or assured demand reduction in excess of its projected demand for the next one or more years. Significant new capacity (over 18,000 megawatts) was developed within Texas between 1997 and 2002 in large part because retail regulators required the state's regulated utilities to own or contract for enough capacity or interruptible demand to assure a 15% reserve margin beyond realistic load forecasts. LSEs may do this through financial or physical contracts that provide assured markets for capital investors. Region-wide, this requires regulators or an regional transmission organization to assure that no supply resources are being double-counted by the LSEs.

Some commentators describe options 2 and 3 as imposing a tax or reliability insurance requirement upon all customers.

4) <u>Economic development incentives</u> – In Michigan in particular, state and local officials have aggressively courted new generation for its economic development benefits, bringing new jobs and protecting existing industries, with the result that over 4,500 MW is on-line or under construction, with another 4,800 in permitting. This approach is beneficial for a local area, but (unless there are significant transmission constraints protecting a load pocket) it does not assure that in real-time the energy rights stay in-state.

**Physical vs. Contractual Methods of Ensuring Adequate Capacity Reserves**

The policies to ensure adequate capacity can be distinguished by whether the capacity obligation is tied only to physical resources, or to contractual as well as physical resources. As noted above, the Northeast markets rely only on physical "iron in the ground" as ICAP credits. Alternative proposals allow for contractual resources such as long-term firm energy contracts to count towards capacity obligations.

Considerations about physical resources:

- Particularly through an absolute reserve margin requirement, it is consistent with traditional reliability planning methods. Loss of load probability (LOLP) models can be used and physical supply and demand resources can be evaluated by reliability planning authorities.
- Having physical resources (supply and demand) available may provide more certainty to system operators that they will be able to balance the system.
- Demand response can be included as ICAP or reserve credits.
- Distant resources can be included as long as they have firm transmission capacity rights to the load.
- Resources which sell their capacity as ICAP have agreed to provide other services to the system, such as a commitment to always bid unless physically unavailable.
- Methods such as ICAP transfer funds from ratepayers to existing generators; it is not clear that ICAP has been responsible for any significant new generation construction.
- Physical reserve margin requirements have clearly caused increases in new generation and interruptible demand in Texas (currently) and elsewhere (historically).
- Because ICAP is a tradable product, it is possible for a supplier controlling a large quantity of generation to exercise market power and manipulate ICAP prices.
- In the Northeast, when ICAP resources are called, there is no transparent price to signal the need for additional emergency sales, only pay-as-bid bilateral purchases by system operators. Even with ICAP, balancing supply and demand is often more a matter of attracting enough imports than one of keeping internal units available.

Considerations about contractual resources:

- Contractual resources are less susceptible to market power because customers have more options. Customers can purchase more distant resources and buy-through congestion, rather than relying on units that have reserved firm transmission on a long term basis. Customers can combine and repackage long-term energy contracts.
- Potentially more amenable to demand response. The terms and conditions imposed on demand participants would likely be less rigid than they are for ICAP.
- Product is consistent with the standard “firm energy” products. Thus more market participants trade in the same “currency,” leading to more liquidity and more efficient exchange.
- Requirements for LSEs to demonstrate sufficient contractual resources to cover peak demand could be imposed. This requirement could last for several years and smooth out boom/bust cycles.
- Contractual resource assurance raises fewer barriers to seams trading because there is always a transparent price.

- Regulators need to determine whether it is acceptable to substitute firm contracts for energy and capacity (with financial risks on the non-LSE counter-party) in lieu of a contract from a specific generation source.
- As with physical assets, regulators need to verify that no resource or contract is being double-counted (claimed by more than one LSE).

**Questions for Regulators to Consider**

1. Whose job is it to assure reserve adequacy? What can state regulators do to assure reserve adequacy for their LSEs and retail customers? Can state regulation alone assure reserve adequacy or is there a role for regional coordination or state-federal cooperation across regions? Can state and federal action, in coordination with ISO or RTO regional planning, be effective to deliver reserve adequacy?

2. Which of the available methods is likely to be the most effective at getting new generation capacity and/or demand management on-line? What are the likely costs and risks to investors and end-use customers from each method?

3. Is it necessary or appropriate to standardize reserve adequacy methods across a region or the nation? If we do not standardize the reserve adequacy method, could significant seams trading problems result?

4. If there is a capacity reserve obligation, should it be physical only, or contractual as well?

5. If there is an adequate demand response program in place across the market region, is it necessary to retain a 1 day in 10 years Loss of Load Probability or 15% reserve margin standard to assure excess capacity for both reliability and price volatility mitigation?

6. What is the appropriate balance between demand and supply resources in meeting long-term and short-term reserve requirements? Whose job is it to determine and effect this balance, state or regional regulators or the RTO planning process?

7. How much excess reserves is enough? How much excess capacity do we want to ask customers to pay for? How should the cost of reserves be balanced against the benefits of reserves?